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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON ORDER INSTITUTING RULEMAKING REGARDING POLICIES, PROCEDURES AND RULES FOR DEVELOPMENT OF DISTRIBUTION RESOURCES PLANS PURSUANT TO PUBLIC UTILITIES CODE SECTION 769

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I. INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure and Ordering Paragraph 4 of the *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, Southern California Edison Company (SCE) respectfully submits these comments on the OIR.

SCE appreciates the opportunity that the Commission's OIR provides to create a forum for stakeholders to provide their viewpoints on the Distribution Resources Plan ("DRP") proposals being prepared by the investor owned utilities ("IOUs"). SCE supports using this process to establish clear, timely procedures and policies which would guide the IOUs as they develop their respective DRPs. In response to the questions identified in the OIR, SCE provides its initial views on the key elements within the OIR's scope.

SCE believes the overarching goal of its DRP should be to facilitate integration of Distributed Energy Resources ("DER") at optimal locations in a manner that minimizes overall system costs and maximizes ratepayer benefits from investments in DER, while at the same time maintaining system safety and reliability. To accomplish this goal, SCE is pursuing substantial analysis to understand how its existing planning activities can be modified to incorporate DERs. The DRPs must be submitted by July 2015. As such, SCE recommends that the Commission's guidance must be provided quickly, to allow time for such guidance to be effectively incorporated into SCE's DRP.

SCE supports the OIR's preliminary scope and schedule.[1] However, SCE notes that some of the questions identified in Section 3.1 of the OIR go beyond the preliminary scope and the DRP requirements of Section 769, and seek to address broader policy issues relating to the evolution of the existing distribution system. SCE supports continued efforts to explore potential future planning frameworks, and has actively participated in discussions on this topic. However, such broad, preliminary policy change exploration on the evolution of the distribution system structure should not interfere with the more immediate challenges associated with achieving the objectives of Section 769. Thus, SCE believes that the initial focus of the OIR should remain on the foundational issues related to establishing a distribution planning framework that enables integration of DERs into the distribution system in a cost-effective manner and ensures adequate testing of grid functionalities to gather operating experience on how new technologies might impact both the distribution system and, more generally, the overall electrical system. Any expansion of focus beyond these foundational issues—to broader issues relating to the evolution of the organization and structure of the distribution system—will inhibit development of the foundational issues upon which any future evolution must be based. Further, such expansion is not necessary to implement the Section 769's DRPs and it would likely slow the process to establish the Commission-guided DRP framework. Accordingly, SCE respectfully requests that

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[1] OIR, R.14-08-013, at pp. 5-6, 10.

the scope of this proceeding remain limited to the preliminary scoping issues identified in Section 3 ("Preliminary Scope") of the OIR.

II. SCE COMMENTS ON QUESTIONS IDENTIFIED IN SECTION 3.1 OF THE OIR

1. What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources and enables the achievement of California's energy and climate goals?

Existing system planning criteria and guidelines are sufficient to ensure a reliable, safe and resilient distribution system and should continue to be the foundation for distribution planning. These guidelines include, for example, a distribution system that can support a "one in ten year heat event" and that can withstand an "N-1 scenario" (where there is loss of a critical system element such as a major transformer or circuit) without exposing customers to extended outages. Similar to these established criteria, specific criteria must be developed to permit an IOU to determine whether a DER can be relied upon to support those foundational elements. Such dependability criteria should demonstrate that a DER provides sufficient reliability to replace, where possible and appropriate, traditional distribution planning solutions.

Optimal location criteria should focus on the primary underlying cost-benefit analysis: (1) the costs saved by the deferral of a traditional capital investment in the distribution system, compared to (2) the costs associated with the DER that allows such deferral. This will entail identification of optimal locations for DERs, which can supplement the existing distribution planning process.[2]

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[2] However, given the complexity and uncertainty inherent in changing the existing distribution planning process to incorporate reliance on new technologies in novel ways, SCE believes that where a DER project is relied upon for system reliability in lieu of a traditional capital investment, there should also be a parallel identification of a utility capital project that can be relied upon as a backstop.

2. What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

A DRP should include the following elements to ensure compliance with AB 327:

a. Discuss DER Locational Benefits and Costs Evaluation. The DRP should identify optimal locations that maximize benefits of DER based upon a defined method. This methodology should include analysis of: (1) local generation capacity needs; (2) avoided costs due to use of DER rather than traditional capital investments in distribution infrastructure to meet those needs; (3) safety requirements; (4) reliability requirements; (5) applicable regulatory requirements; and (6) other savings and costs associated with deployment of DER at a specific location to meet grid needs. The DRP should address how DERs are incorporated into planning processes at different levels, including: (1) distribution forecasting; (2) dependability analysis; (3) DER optimization analysis; (4) transmission planning; and (5) generation planning.

b. Propose mechanisms to deploy cost-effective DERs that satisfy distribution planning objectives. The DRP should propose mechanisms to facilitate deployment of DER into distribution planning.

c. Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives and tariffs. The DRP should describe how existing programs, tariffs, incentives and contracts can be integrated with distribution planning activities.

d. Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning. The DRP should describe how the proposal supports and encourages penetration of DER. The DRP should also provide a roadmap for investment of grid devices, communications and other grid management tools that are necessary to facilitate DER penetration.

e. Identify barriers to the deployment of distributed resources. The DRP should describe non-economic barriers the utility will encounter when pursuing deployment of distributed resources (e.g., safety, reliability and loading standards, environmental constraints, local regulatory requirements, customer participation, etc.).

3. What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

Optimal location criteria should include:

- **Optimization Analysis.** Identification of locations where DERs can optimize loading at distribution, subtransmission and transmission levels.
- **Local Capacity Requirements.** Identification of locations where local capacity requirements can be supported with DER development.
- **IOU Capital Cost Avoidance Analysis**. Locational review for potential future cost avoidance to the extent that DERs can be reliably and cost-efficiently deployed in lieu of major IOU capital projects.
- **DER Deployment Cost**. Identification of locations that could accommodate significant DER interconnection without need for significant upgrades.
- **Dependability Analysis.** Assessment of the ability of DERs to meet reliability needs.

4. What specific value should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERS for this value?

The locational value of a DER should be determined based upon the location-specific electrical impact of a DER (i.e., the physical location of the DER and the associated locational system costs and benefits). This analysis should include a comprehensive review of the costs and benefits, including any costs related to managing reliability impacts, associated with relying upon DER rather than a traditional IOU capital investment to meet distribution planning and reliability needs. This location-specific valuation should also consider the optimal location criteria outlined in SCE's response to Question No. 3.

As a general principle, when third party supply is sought, SCE favors reliance on competitive solicitations rather than administratively determined pricing to select the most cost effective DERs and to provide the best value to SCE's distribution system customers. This suggests a planning process in which locational needs are first identified and then used to shape the procurement and/or valuation process.

5. What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

The following specific considerations and methods should be considered:

- **Distribution Grid Operator Flexibility Considerations.** The DRP should ensure the distribution grid operator's ability to seamlessly reconfigure distribution circuits is consistent with current practice.
- **Review of Technologies Required to Facilitate Resources as Grid Assets.** The DRP should permit system upgrades as needed to support the integration of DERs. It must include an analysis of technologies that could facilitate (1) DER interoperability and interface with grid equipment such as communication systems, (2) expansion of distribution assets, (3) monitoring and control software, tools, and schemes, along with (4) procedures in support of distribution reliability.
- **Data Collection and Analysis.** To integrate DERs into IOU distribution planning and operations, the DRP should include methods that permit the IOU to obtain and review data sufficient to evaluate the characteristics and performance of DER technologies. This is particularly important at the outset when the potential risks from saturation or unexpected interactions across DER technologies are not well understood.
- **Other considerations**. Other considerations regarding integration should include:
    - How the resource is accounted for when evaluating recorded load;
    - Load Forecasting (e.g., how DERs are factored into the long-term electrical demand forecast and the supporting methodologies);
    - Evaluation of potential ways to achieve dependability (e.g., over-subscription; combining resources; contractual terms; physical assurance);
    - Optimization (e.g., how naturally occurring DERs can fulfill need);
    - Aggregate distribution impacts to the transmission planning process;
    - Aggregate distribution impacts to the generation capacity planning process;
    - Measurement and validation techniques for DERs.

6. What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

The following distribution planning and operations methods and analysis should be considered to support the provision of distribution reliability services by DERs:

- **Demand Profile Methods:** The IOU should evaluate demand profiles and the ability for DERs to meet expected profiles as part of the planning process.
- **DER Control Methods:** The IOU must be able to control operation of DERs to support reliability grid needs.
- **DER Monitoring Methods:** To effectively and reliably utilize DERs, there must be increased monitoring of DER output and power flow.
- **DER Dependability Methods:** Planning criteria must be developed to reflect the DER's availability, location and dependability.
- **Distribution Grid Operator Control Considerations:** The DRP should ensure the distribution grid operator's ability to seamlessly reconfigure distribution circuits is consistent with current practice.
- **Review of Technologies Required to Facilitate Resources as Grid Assets.** The DRP should permit cost-effective system upgrades as needed to support the integration of DERs. It must include an analysis of technologies that could facilitate (1) DER interoperability and interface with grid equipment such as communication systems, (2) expansion of distribution assets, (3) monitoring and control software, tools and schemes, along with (4) procedures in support of distribution reliability.

7. What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

The primary benefits of a DER should be determined based upon the specific electrical impact of a DER (i.e., the physical location of the DER, the associated locational system costs and benefits, and the associated collective electrical system costs and benefits) within the distribution grid. This analysis should include a review of the costs and benefits associated with relying upon DER as compared to a traditional IOU capital investment to meet distribution planning and reliability needs. This location-specific valuation should also consider the optimal location criteria and associated values outlined in SCE's response to Question No. 3.

8. What criteria and inputs should be considered in the development of scenarios and or/guidelines to test the specific DER integration strategies proposed in the DRPs?

DER integration strategies proposed in the DRPs should be reviewed based upon the same measurement and evaluation tools that are being developed to determine optimal location value, as discussed in SCE's answers to Question Nos. 3 and 4. In addition, an analysis regarding impact to customer rates, as well as interaction with existing regulatory framework, should be performed. Distribution system needs can vary substantially among specific areas and the penetration of DERs may vary, as well. Thus, there will likely be a considerable amount of diversity of DER impact across SCE's service area.

9. What types of data and level of data access should be considered as part of the DRP ?

SCE believes an IOU should consider the following types of data:

- **Utility System Data.** Data relating to aggregate peak and minimum load data, or output curves, at the substation level.
- **Planned Major Capital Project Data.** Identification of major IOU facilities expected to be overloaded in the three to ten year horizon (projects identified within a two year horizon would already have committed expenses).
- **DER Data.** Data relating to DER functionality and performance. Such data includes:
  - Existing and forecasted penetration levels of DERs;
  - Detailed voltage, amp, KW and KVA along with real time DER information;
  - Detailed customer loading and behind the meter equipment information to analyze potential for load reduction with DER use;
  - SCADA and Telemetry data related to DERs;
  - Baseline data determination for EE and DR measures.
- **Optimal Location Maps.** SCE believes that a viable method for communicating the output of optimal location analysis can be accomplished by expanding the scope of information identified in IOUs' existing interconnection maps with additional information layers relating to optimal locations to assist with stakeholder review.

Regarding the appropriate level of public access to such data, SCE believes that some of this data may be protected from public disclosure pursuant to North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) regulations, Critical Energy Infrastructure Information (CEII) regulations, customer confidentiality requirements and/or other confidentiality requirements. If protected, such information can only be made available if and as permissible under the law.

10. **Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that the IOUs should consider?**

The DRP should identify specific grid modernization technologies and other system improvements that will be required to support DER integration safely and reliably. As DER penetration increases, SCE anticipates a dynamic process whereby the experience gained from initial installations will allow SCE to further develop operating experience and knowledge regarding how to best incorporate and manage high penetration of DERs on its system.

However, SCE is not relying solely upon its DRP to accomplish this purpose. SCE has actively pursued a variety of pilot projects seeking to improve its understanding of DER integration, ranging from relatively technical projects such as the Tehachipi battery storage unit, to distribution integration projects such as the Irvine Smart Grid demonstration, to need-based initiatives such as the Preferred Resources Pilot. The use of pilot demonstrations, either as part of the DRP or independent from the DRP, will provide invaluable information regarding how DERs can be integrated into the electric system. SCE also intends to employ existing capital programs, where permissible, to immediately start testing system improvements and grid modernization technologies to gain additional feedback and data. SCE can then apply the measurement and evaluation tools being developed in the DRP to measure the success of these pilots and/or existing programs.

11. <u>What considerations should the Commission take into account when defining how the DRPs should be monitored over time?</u>

SCE believes the DRPs should continue to be monitored following Commission approval, with an update approximately every three years. This update should include data that tracks DER penetration by DER type, as well as data that tracks DER capabilities and performance at each identified optimal location. This will permit integration of additional data, technology and knowledge that was developed since the previous DRP filing. This will also permit the Commission to measure the benefits of the DRP and evaluate its strengths and weaknesses.

12. <u>What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?</u>

The overarching principle should be to facilitate integration of DER at optimal locations in a manner that minimizes overall system costs and maximizes ratepayer benefit from investments in DER, while at the same time maintaining system safety and reliability. This principle should be informed by clear, articulated reliability performance criteria and performance measurements for DERs, as well as by grid investment recommendations measured over a long cycle (to account for the time required to deploy ever-evolving technologies).

13. Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable

Pursuant to the Public Utilities Code, utilities have the sole responsibility and obligation to ensure the safe and reliable delivery of power at the local level. *See* Pub. Util. Code §399.2(1) ("It is the policy of this state, and the intent of the Legislature, to reaffirm that each electrical corporation shall continue to operate its electric distribution grid in its service territory and shall do so in a safe, reliable, efficient, and cost-effective manner"). Accordingly, a utility is "responsible for operating its own electric distribution grid, including . . . owning, controlling, operating, managing, maintaining, planning, engineering, designing, and constructing its own electric distribution grid." *See* Pub. Util. Code §399.2(2). Consequently, utilities have the statutory obligation to own and operate the distribution assets that comprise the distribution grid. Beyond that, the question of ownership raises many complex and difficult legal, regulatory, reliability and safety issues.

Questions regarding ownership are beyond the scope of the DRP, as outlined in Pub. Utils. Code Section 769 and can only serve to distract from moving the DRP forward in the most constructive fashion. SCE believes that the focus of this proceeding should address development of a DRP that identifies optimal locations for DER and successfully implements such DER into the distribution planning process in a safe, reliable and cost efficient manner. This proceeding, to succeed in the time available, must focus on the on the interoperability between the IOU electric system and DER devices. Such focus will assist with key foundational issues relating to integration of cost-effective DERs and reduction of barriers to the deployment of DERs (such as limitations on penetration due to communication issues).

14. What specific concerns around safety should be addressed in the DRPs?

Safety issues discussed in this section are limited to the interconnection, operating and metering requirements for the safe and reliable operation of a customer's generating facility in parallel to and connected to SCE's grid. SCE notes that there are safety issues relating to a third-party's generating facility that are outside of interconnection and operating requirements and those should be addressed separately.[3]

Regarding distribution system safety concerns, DERs run in parallel with the grid and thus impact safety in a variety of ways, including: the creation of multiple generation sources (back-feed); fault contribution; voltage impacts; and potential for customer islanding. SCE's Rule 21 governs the interconnection, operating and metering requirements for a safe and reliable operation of those DERs connecting to SCE's distribution system. Any proposals to alter such requirements to facilitate DER interconnection should not be addressed in this OIR.[4]

Regarding distribution system operations concerns, DERs create safety and reliability concerns related to intermittency and availability during extreme conditions. In addition, the complexities created by reliance on DERs could lead to increased risk for day to day grid operator activities that impact the status of energized lines required to protect utility workers. Such risks must be carefully addressed.

Finally, the DRPs must also consider cybersecurity standards and threat prevention.

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[3] These safety issues could relate to a generating facility's compliance with the codes and standards of the appropriate specific state or local permitting authority, and the related safety risks arising out of the interaction between the generating facility and the owner's environment. *See* Decision 14-05-003, Rulemaking 12-11-005, at p. 30 (discussing interconnection of storage devices to the IOU distribution system and stating "[s]everal parties commented that while there are standards and rules addressing safety, there is a lack of coordination at the state level. We agree. In order to facilitate a more cohesive set of standards and practices, we direct Commission staff to work with the state-wide entities such as the Governor's Office of Planning and Research and the Office of the State Fire Marshall to identify existing best practices and, if necessary, develop a set of best practices to improve permitting and inspection by local authorities.").

[4] Such proposals should be addressed in the active Rule 21 OIR, R.11-09-011.

15. What, if any, further actions should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs.

The Commission must consider the need for IOU investment to cost-effectively integrate DERs into distribution system and maximize the potential benefits. SCE anticipates that a set of investments will be required to modernize the grid and accomplish the overarching principle of the DRP (i.e., to facilitate integration of DER at optimal locations in a manner that minimizes overall system costs and maximizes ratepayer benefit from investments in DER, while at the same time maintaining system safety and reliability).

SCE also notes that the DRP should not restrict its existing ability to commence with small, near term distribution system planning and upgrades. SCE needs such flexibility to maintain the safety and reliability of the distribution system.

16. SCE Response to Appendix B, "More Than Smart" White Paper Questions

SCE appreciates the forward-looking, proactive approach embodied in the *More Than Smart* white paper. It is an expansive, broad initial attempt to develop a roadmap for the future evolution of the distribution system. However, as noted above, SCE believes the focus of this proceeding should be on developing an appropriate framework for implementing the DRPs pursuant to Pub. Utils. Code Section 769.

Section 769 requires the IOUs to submit a DRP that "identif[ies] optimal locations for the deployment of distributed resources." The statute requires a careful cost-benefit analysis for determining those optimal locations, as well as a review of the regulatory framework, the potential barriers to deployment, and the potential utility spending relating to a successful identification of distributed resources. This is a significant undertaking, and SCE believes this proceeding must initially focus on establishing a framework to guide the development of these substantial plans. In that context, the white paper offers valuable insight. For example, the white paper notes that, to ensure that ratepayers realize the net benefits from the optimal use of distributed resources at minimal cost, there must be: (1) "[a]n integrated planning and analysis framework to properly identify the criteria, issues, interdependencies and methods of analysis;" (2) a "[s]tandardized set of related analytical models and techniques to achieve comparable results;" and (3) "[t]ransparent processes incorporating relevant stakeholder participation" (specifically, as relates to the development of optimal locations).[5] SCE supports the white paper's conclusion which states that prior to submitting distribution planning under AB 327, "[f]raming the planning objectives in a practical and standard manner is essential to yield comparable results across the state."[6]

However, the white paper goes beyond the scope of Section 769 when it shifts to a more expansive, futuristic framework regarding the "evolution of the existing distribution system to

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[5] Order Instituting Rulemaking (filed Aug. 14, 2014), R.14-08-013, at Appendix B, pp. 5-6.
[6] *Id.* at Appendix B, p. 6.

become an enabling network."[7] These topics contemplate significant changes to the electric system, which the paper acknowledges is "the most complex machine developed by humans."[8] Important open issues remain including: how to establish workable jurisdictional clarity between FERC-regulated wholesale markets and bulk-electric system reliability standards vs. Commission-regulated distribution systems and customer reliability standards; the role that customer loads and customer load management must play as part of distribution grid planning and operations; and the role that wholesale prices should play in informing and encouraging appropriate use of the distribution grid by both customer loads and DERs. Before addressing such outstanding issues, extensive analysis is required regarding not only contemplation of evolutionary steps, but also the existing capabilities of the distribution system and distribution planning process upon which such evolution will depend. The white paper, itself, notes that its discussion is intended to simply be part of a continuing "conversation among a diverse set of experts"[9] and a discussion point for continued workshops and analysis. It is inappropriate and premature to adopt such a white paper to govern a narrower, time-limited set of Section 769 issues. Accordingly, SCE does not believe this white paper should be used as the set of criteria to govern the IOUs' DRPs.

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[7] *Id.* at Appendix B, p. 3.
[8] *Id.* at Appendix B, p.4.
[9] *Id.* at Appendix B, p.3.

III. CONCLUSION

SCE appreciates the opportunity to submit these comments.

Respectfully submitted,

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